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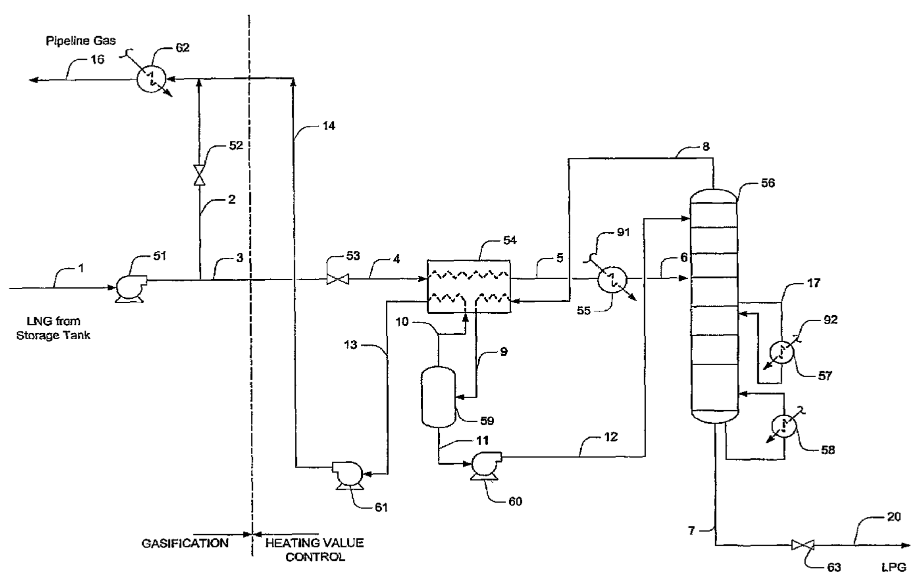
(54) Title: LNG REGASIFICATION CONFIGURATIONS AND METHODS



(57) Abstract: LNG composition of LNG from a storage tank or other source is modified in a process in which the LNG is pumped to a first pressure and split into two portions. One portion of the pressurized LNG is then reduced in pressure and heavier components are separated from the reduced pressure LNG to thereby form a lean LNG. The lean LNG is then pumped to a higher pressure and combined with the other portion to form a leaner LNG. Preferably, separation is performed using a demethanizer, wherein part of the demethanizer overhead product is condensed to form the lean LNG, while another portion is used for column reflux. In further preferred configurations, ethane recovery is variable and in yet other configurations, propane or ethane can be delivered via a batching pipeline.

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LNG REGASIFICATION CONFIGURATIONS AND METHODS

This application claims priority to our copending U.S. provisional patent applications with serial numbers 60/584,611, and 60/683,181, which were filed June 30, 2004 and May 20, 2005, respectively, and which are both incorporated by reference herein.

Field of The Invention

The field of the invention is gas processing, especially as it relates to regasification of liquefied natural gas for heating value control, and recovery or extraction of C2, and C3 plus components for sales.

Background of The Invention

As the demand for natural gas in the United States has risen sharply in recent years, the market price of natural gas has become increasingly volatile. Consequently, there is a renewed interest in import of liquefied natural gas (LNG) as an alternative source for natural gas. However, most import LNG has a higher heating value and is richer in heavier hydrocarbons than is allowed by typical North American natural gas pipeline specifications. For example, while some countries generally accept the use of richer and high heating value LNG, the requirements for the North American market are driven by ecological and environmental concerns and may further depend on the particular use of the LNG.

One of the problems with LNG import is that a substantial fraction of the world LNG supply is rich LNG with non-compliant heating values. As the LNG import market grows, spot LNG trades are becoming more common, similar to today's crude oil trade market. With increasing LNG trading between different LNG producers and North American regasification sites, LNG terminals must be configured to accept LNG with various compositions and heating values to remain regulation compliant and cost competitive. In some markets, rich LNG can be made profitable as its ethane content can be used for petrochemical plant feedstock, the propane content can be sold as LPG, and the butane plus liquid can be used for gasoline blending. Additionally, processing steps for extraction of the heavier components from the rich LNG are necessary to meet the stringent North America pipeline heating value specification.

In most upstream LNG liquefaction plants, removal of pentane, hexane, and heavier hydrocarbons is required only to avoid wax formation in the cryogenic liquefaction exchanger. The LPG components (C2, C3 and C4+) are typically not removed and are

liquefied together with the methane component, resulting in LNG with a fairly high gross heating value. Exemplary heating values of LNG from a number of LNG export plants in the Atlantic, Pacific Ocean and Middle East LNG plants are shown in **Figure 8**. The higher heating values indicate a higher proportion of the non-methane components. The compositions of the ethane, propane, and butane and heavier components for these LNG are shown in **Figure 9**.

In North America, many pipeline operators require very lean gas for transmission, and in some mid-west regions, natural gas gross heating value ranges between 960 and 1050 Btu/scf. In California, the acceptable gross heating value is between 970 and 1150 Btu/scf. California also imposes constraints on specific gas components for compressed natural gas consumption. Currently, acceptable LNG that meets the California specification is limited to sources such as the Kenai, Alaska LNG, or the Atlantic LNG from Trinidad. Therefore, to meet North American natural gas specifications, regasification terminals must have facilities that are capable of processing non-compliant LNG. Most commonly, LNG heating value and Wobbe Index are controlled by dilution with nitrogen, or blending with a leaner natural gas. However, there are limits on the maximum amount of nitrogen and inerts that can be introduced to the pipeline gas. Moreover, dilution with nitrogen often requires an air separation plant to produce the nitrogen, which is costly and produces no other benefit for the facility, and a lean gas source is often not available for blending in a relatively large LNG regasification facility.

As environmental regulations become more stringent, tighter control on LNG compositions than the current specifications are expected in the North American markets, requiring new processes that can economically remove the C_2+ components from LNG. Moreover, such processes should advantageously provide a plant with sufficient flexibility to handle a wide range of LNG allowing importers to buy LNG from various low cost markets instead of being limited to those sources that meet the North America specifications.

Conventional processes for regasifying rich LNG (*e.g.*, LNG from Indonesia is typically at 1200 to 1300 Btu/SCF) involve heating the LNG in fuel-fired heaters or with seawater heaters, and then diluting the vaporized LNG with nitrogen or a lean gas to meet the heating value specification. However, either heating process is undesirable as fuel gas heaters generate emissions and CO_2 pollutants, and seawater heaters require costly seawater systems and also negatively impact the ocean environment. Furthermore, dilution with nitrogen to

control the natural gas heating value is typically uneconomical as it generally requires a nitrogen source (*e.g.*, an air separation plant) that is relatively costly to operate. While the dilution methods can produce "on-spec" heating values, the effects on LNG compositions are relatively minor, and the final composition (especially with respect to C_2 and C_3+ components) may still be unacceptable for the environmental standards of the North America or other environmental sensitive markets. Consequently, a LNG stripping process or other gas fractionation step must be employed, which generally necessitates vaporizing the LNG in a flash drum and stripping in a demethanizer operating at low pressures, with the flash vapor and/or demethanizer overhead compressed to a higher pressure and re-condensed to a liquid form using inlet LNG as a coolant and then pumped and vaporized in the vaporizers. These processes are energy inefficient when high propane and ethane recoveries are required on processing richer LNG (LNG with high ethane and propane and heavier content) for regulation compliance, because these processes would require operating the flash drum and demethanizer at an even lower pressure that would significantly increase the compression costs. An exemplary regasification process and configuration is described in U.S. Pat. No. 6,564,579 to McCartney.

In addition to removal of C2+ components to meet sales gas heating values, there are also revenue opportunities for producing C2 and C3 for sales since the value of these NGL components is generally higher than that of natural gas, especially when ethane can be used as petrochemical feedstock, and the propane and heavier components can be sold as transportation fuel. Unfortunately, the consumer markets of these liquid products are typically at a significant distance from the LNG regasification terminals, and dedicated pipeline transportation systems would have to be installed. Additionally, the C2 or C3 market is often subject to seasonal fluctuation. Therefore, there is a need to provide flexibility that allows a facility to operate on either ethane recovery or ethane rejection (propane recovery only), or that allows varying ethane recovery level. Unfortunately, most current NGL plants fail to address these operating modes, subsequently losing the potential revenue benefits from the operation from ethane recovery to ethane rejection or vise versa.

Consequently, while numerous processes and configurations for LNG regasification are known in the art, all of almost all of them suffer from one or more disadvantage. Most notably, many of the currently known processes are energy inefficient, and inflexible in

meeting the heating values and composition requirements. Thus, there is still a need to provide improved configurations and methods for gas processing in LNG regasification.

Summary of the Invention

The present invention is directed to configurations and methods of processing LNG in which the pressure of one portion of the LNG is set to a processing pressure at which LNG processing takes place to thereby generate a processed (typically lean) LNG. The so formed processed LNG may then be further pressurized to a delivery pressure and combined with a second portion of (typically unprocessed) LNG at delivery pressure to so generate LNG with a desired and predetermined chemical composition and heating value. Preferably, processing of the LNG is performed in a refluxed demethanizer that allows removal and/or recovery of at least 99% propane and over 70% ethane from the LNG.

In one aspect of the inventive subject matter, a LNG processing plant includes a LNG source that provides a first portion of LNG and a second portion of LNG. A processing unit is fluidly coupled to the LNG source and receives the first portion, wherein the unit removes heavier components in the first portion to thereby produce a lean LNG. A combination unit then combines the lean LNG and the second portion of the LNG to a form a processed LNG.

Preferably, contemplated LNG processing plants comprise a pump that pumps at least one of the first and second portions to a feed pressure, and further include a demethanizer that receives at least part of the second portion at a pressure lower than the feed pressure. Most preferably, the demethanizer produces an overhead product, wherein a heat exchanger cools at least part of the demethanizer overhead vapor to thereby produce a reflux stream for the demethanizer, and/or wherein a heat exchanger condenses at least part of the overhead vapor from the demethanizer reflux drum to thereby produce the lean LNG.

In still further preferred aspects, contemplated LNG processing plants are configured to combine the first portion and the lean LNG to thereby form the processed LNG, and the processed LNG is then pumped and vaporized at pipeline pressure in a manner well known in the art. Moreover, contemplated plants may also include a control circuit that is configured to control a mass flow ratio between the first and second portion. Using such control circuits, it should be appreciated that the heating value of the combined processed and unprocessed LNG can be maintained at a predetermined level while the LNG entering the plant may have variable chemical compositions and/or heating values. Where desired, the plant may further

include a turbo-generator that is driven by expansion of a heated and pressurized portion of the first portion of LNG to thereby produce energy.

In another aspect of the inventive subject matter, the LNG processing plant has a heat exchanger that is configured such that at least part of a refrigeration content of LNG passing through the exchanger provides refrigeration to a demethanizer reflux stream and further provides condensation cold for a demethanizer reflux drum overhead product, and wherein the reflux stream and the demethanizer reflux drum overhead product are produced from the LNG passing through the exchanger. Particularly preferred plants also include a demethanizer that is coupled to the exchanger such that at least part of the LNG passing through the exchanger is fed to the demethanizer to thereby form at least one of the demethanizer reflux stream and a condensed demethanizer reflux drum overhead product. Most typically, the LNG passing through the exchanger has a pressure of between 300 psig to 600 psig. A pump may be coupled to the exchanger that pumps the condensed demethanizer reflux drum overhead product to a delivery pressure, and a combination unit may be included in which the condensed demethanizer reflux drum overhead product at delivery pressure is combined with LNG.

Consequently, the inventors contemplate a method of processing LNG in which in one step LNG is provided and pumped to a feed pressure. In a further step, the LNG is divided at feed pressure in a first and second portion. In yet another step, pressure is reduced in the first portion to a separation pressure and heavier components are separated from the first portion at the separation pressure to thereby form a lean LNG. In still another step, the lean LNG is pumped to a delivery pressure, and the lean LNG and the second portion of the LNG are combined to form a processed LNG.

Preferred feed pressures are between about 700 psig and 1300 psig, while separation pressures are preferably between about 300 psig and 650 psig, and delivery pressures are preferably between about 700 psig and 1300 psig. Separation of the heavier components from the first portion is typically performed in a demethanizer that produces a demethanizer overhead product, wherein most preferably at least one portion of the demethanizer overhead product is condensed to thereby form the lean LNG, and optionally another portion of the demethanizer overhead product is cooled to form a reflux stream for the demethanizer.

In especially contemplated plants where ethane recovery or ethane rejection or varying levels of ethane recovery is desirable, the demethanizer bottoms can be further processed in a

deethanizer column to produce a C2 overhead liquid, and a C3+ bottoms product. In this case, the deethanizer overhead reflux duty can be supplied by the refrigeration content of the inlet LNG. Ethane rejection or varying level of ethane recovery can be efficiently achieved by diverting at least a portion of the liquid ethane product from the deethanizer overhead to blend with the lean LNG. Such configuration allows the flexibility of switching between ethane recovery to ethane rejection mode or vise versa, without altering the upstream processing conditions.

Various objects, features, aspects and advantages of the present invention will become more apparent from the following detailed description of preferred embodiments of the invention, along with the accompanying drawing.

Brief Description of The Drawing

Figure 1 is a schematic view of a first exemplary plant according to the inventive subject matter with removal or recovery of 99% of propane in the inlet LNG.

Figure 2 is a schematic view of a second exemplary plant according to the inventive subject matter with removal or recovery of over 70% of ethane and 99% of propane in the inlet LNG.

Figure 3 is a schematic view of a third exemplary plant according to the inventive subject matter with removal or recovery of 99% of propane in the inlet LNG using an integral reflux condensing exchanger.

Figure 4 is a schematic view of a fourth exemplary plant according to the inventive subject matter for a plant that recovers C_2 and C_3 while producing energy.

Figure 5 is a schematic view of a fifth exemplary plant according to the inventive subject matter for a plant that recovers C_3 while producing energy.

Figure 6 is a schematic view of a sixth exemplary plant according to the inventive subject matter with removal or recovery of 99% of propane and 2% to 70% ethane recoveries from the inlet LNG, demonstrating the switching method between ethane recovery to ethane rejection or varying levels of ethane recovery.

Figure 7 is a schematic view of a seventh exemplary plant according to the inventive subject matter for propane or ethane delivery using a batching NGL pipeline.

Figure 8 is a graph depicting heating values of LNG from various LNG export plants in the Atlantic, Pacific and Middle East market.

Figure 9 is a graph depicting chemical composition of LNG for the LNG of Figure 8.

Detailed Description

The inventors discovered that LNG can be processed in a manner that takes advantage of the relatively large refrigeration content in the LNG. More specifically, the inventors have discovered that an LNG stream can be pumped to a desired pressure and then used to supply reflux cooling in a demethanizer and condensing duty of the demethanizer reflux drum vapor to thereby produce a lean LNG that can then be combined with unprocessed LNG.

Optionally, the refrigeration content of the LNG may also supply reflux cooling in a deethanizer. Most preferably, the pumped LNG stream is processed in a demethanizer (and optionally deethanizer) to thereby form the streams that are cooled by the pumped LNG. Such configurations advantageously allow removal or recovery of at least 99% propane and over 70% ethane from the LNG. Where ethane rejection or varying levels of ethane recovery is desirable, the demethanizer bottoms can be further processed in a deethanizer column to produce a C2 overhead liquid, and a C3+ bottoms product wherein ethane rejection or varying ethane recovery can be efficiently achieved by diverting at least a portion of the liquid ethane product from the deethanizer overhead to blend with the lean LNG.

In one preferred aspect of the inventive subject matter as depicted in **Figure 1**, LNG is pumped and split into two portions (streams 2 and 3) as needed for heating value control. The first portion is heat exchanged with the demethanizer overhead producing a cold reflux and condensed demethanizer overhead product (lean LNG), while the second portion (rich LNG) bypasses the heating value control portion. The rich LNG and lean LNG streams can then be combined to produce a LNG product with desired chemical composition and heating value.

More specifically, and with further reference to Figure 1, The LNG flow rate to the plant is equivalent to 500 MMscfd of natural gas with a typical gas composition shown in Table 1 below. LNG stream 1 from storage or vapor re-condenser (or other suitable source) is at a pressure of about 15 to 80 psia and a temperature of typically about –260°F to –240°F. Stream 1 is pumped by LNG pump 51 to a suitable pressure, typically about 700 psig to about 1300 psig, and most typically about 1000 psig to form a pressurized LNG stream, which is split into stream 2 and stream 3 as needed for heating value control. A higher flow of stream

3 will pass more LNG feed to the heating value control unit, thus lowering the heating value of the pipeline gas 16. Where high propane recoveries are desirable (e.g., due to the market demands), most of LNG stream 1 will be processed in the heating value control unit. Thus, it should be recognized that by varying the flow ratio between streams 2 and 3, the quantity of C_2+ components in the pipeline gas can be controlled to meet specific market requirements.

Stream 3 is letdown in pressure in valve 53 to form stream 4 at about 450 to 500 psig that is heated and partially vaporized in exchanger 54 by heat exchange with the demethanizer overhead stream 8 and reflux separator vapor stream 10. The exchanger outlet stream 5 is at about -120°F to -140°F and is further heated in preheater 55 using a heat transfer medium (e.g., glycol (stream 91)) forming stream 6 at about -120°F to -115°F. The two-phase stream 6 is then fed to the upper section of demethanizer 56. The demethanizer produces a lean natural overhead vapor 8, which is reduced in (or even depleted of) propane and heavier components and at least partially depleted of ethane.

Demethanizer 56 preferably operates at 450 psig to 500 psig. It should be especially noted that side reboiler 57 can be used to assist the stripping of the light components in stream 17 withdrawn from the lower section of the demethanizer, with heat supplied from glycol stream 92. The demethanizer bottom composition is controlled by temperature of stream 7, at about 100°F (ethane recovery) to 200°F (propane recovery only), using bottom reboiler 58. Thus, it should be especially appreciated that in most aspects of contemplated configurations the set point of the demethanizer bottom temperature will control the levels of recovery and provide heating value control of the inlet LNG. Bottom product 7 can then be let down in pressure using valve 63 and sent out as LPG stream 20.

The demethanizer overhead 8, which is typically at a pressure of about 450 psig to 500 psig and a temperature of at about -90°F to -120°F is cooled and partially condensed in exchanger 54 at a temperature of about -110°F to -140°F. The so generated two-phase stream 9 is then separated in separator 59 into a liquid stream 11 and a lean vapor stream 10. Liquid stream 11, containing residual propane and/or ethane components, is pumped by reflux pump 60 and returned to the top of the demethanizer as a cold reflux stream 12. The separator vapor stream 10 is returned to exchanger 54 and further cooled and condensed forming stream 13.

It should be especially recognized that overhead exchanger 54 provides two functions, providing reflux to the demethanizer that is essential to achieve a high propane and ethane recovery, and to condense the separator vapor to a liquid that allows the liquid to be pumped,

thus substantially reducing capital and operational cost. The lean liquid stream 13, typically at a temperature of about -130° to -140°F is pumped by pump 61 to about 1000 psig pressure as necessary for pipeline transportation or combination with rich LNG stream 2. The pressurized lean LNG stream 14 is mixed with stream 2 of the rich LNG and further heated in vaporizer 62 to about 50°F, or other temperature needed to meet pipeline requirements. It should be note that suitable heat sources for the LNG vaporizer include all known heat sources (direct heat sources such as fired heaters, seawater exchangers, etc., or indirect heat sources such as glycol heat transfer systems). Valves 52 and 53 are preferably regulated by a control system (not shown) that adjusts the mass flow between streams 2 and 3 to a predetermined ratio (most typically to achieve a desired chemical composition and/or heating value).

Alternatively, contemplated heat integration and process configurations can also be used for ethane recovery as depicted in the exemplary plant configuration of **Figure 2**. Here, ethane recovery can be varied from 5% up to 80% as needed for heating value control of the rich LNG stream 1. With respect to the numerals of the components of Figure 2, it should be noted that same components of Figures 1 and 2 have same numerals in Figure 2.

In general, the front end of the configuration according to Figure 2 is similar to that shown in Figure 1. However, a second column 64 (the deethanizer) is added such that the deethanizer receives liquid stream 7 from the demethanizer 56. Stream 7 is letdown using valve 63 to a pressure of about 200 psig to 350 psig to form stream 19 that is fed to the mid section of deethanizer 64. It should be appreciated that the operating pressure of the deethanizer can be varied as needed to meet the pressure requirements of the ethane product. The deethanizer overhead stream 21 is advantageously at least partially condensed in exchanger 65 using the refrigeration content of lean LNG stream 14. The two-phase stream 22 at about 0°F to 30°F is separated in separator 66 into a liquid stream 23 and an ethane vapor product stream 25. A portion of the liquid stream is pumped by reflux pump 67 and returned to the deethanizer overhead as reflux stream 24. Optionally, where liquid ethane product is desired, a portion of the liquid can be produced as stream 26. The ethane vapor can be used as a fuel source in the submerged combustion LNG vaporizer, used to fuel a power plant, and/or for petrochemical production. The deethanizer produces a bottom product stream 20 with heat supplied by reboiler 68 (e.g., using a glycol heat transfer system as a heat source). Lean cooled LNG stream 15 can then be combined with the rich LNG and vaporized in heater 62 to form pipeline gas 16 having desired chemical composition and/or heating value.

Alternatively, the overhead reflux exchanger in the demethanizer can be integrated in the column as shown in the exemplary plant configuration of **Figure 3**. Here, pumped rich LNG is used in an overhead reflux condenser 69 integral to the column, producing an internal reflux stream 10 that is free flowing to the lower section of the column. The heated LNG stream 6 from exchanger 69 is sent to the upper section of the demethanizer, below the reflux exchanger 69. Again, with respect to the numerals of the components of Figure 3, it should be noted that same components of Figures 1 and 3 have same numerals in Figure 3.

Therefore, it should be recognized that numerous advantages may be achieved using configurations according to the inventive subject matter. Among other things, it should be appreciated that contemplated configurations (by virtue of modifying the split ratio of the inlet LNG stream and temperature in the heating value control section) allow processing of LNG with varying compositions and heat contents while producing an "on spec" natural gas and/or LNG transportation fuel for the North American market or other emission sensitive markets. Moreover, contemplated configurations will produce high-purity ethane as commercial product or as energy source for the combined cycle power plant.

In a still further contemplated aspect, power can be generated using the LNG. Most preferably, a heat source heats the liquid portion of the LNG (typically after passage of the LNG through the exchanger), wherein the LNG may be further pumped to a higher pressure before heating. The so pumped and heated LNG is then expanded to produce work in an open cycle (typically without the typical re-circulation of the LNG in known configurations) prior to entry into the demethanizer. In especially preferred plants, the LNG processing plant has a demethanizer and a deethanizer, wherein the demethanizer removes C_2+ components from the LNG using the expanded vapor from the expander as a stripping medium, and wherein the reflux duties of the demethanizer and deethanizer overhead condenser are provided by the refrigeration content in the LNG in a manner substantially similar as described above in Figures 1-3. Preferably, the open LNG expansion cycle supplies at least a portion of the power demand for the LNG regasification plant. However, in alternative aspects, so generated power can also be employed in other portions of the plant, or be sold at a premium.

Therefore, it should be appreciated that contemplated plants may comprise a pump and a heat source that heats a first portion of a liquefied natural gas, and an expander in which the pumped and heated liquefied natural gas is expanded to produce work. It is still further preferred that at least a portion of the expanded gas is fed into a demethanizer as a stripping

gas to produce a lean gas (at least partially depleted from ethane) and a demethanized bottom product, wherein the lean gas may be re-condensed using at least part of the refrigeration content of the LNG. The demethanizer bottom product may then be fed to a deethanizer that produces an ethane product and a liquefied petroleum gas product.

Additionally, or alternatively, at least a portion of the reflux condenser duty of the demethanizer and deethanizer is provided by the refrigeration content of a portion of the liquefied natural gas before the heat source heats the liquid portion of the liquefied natural gas, and/or that a second portion of the liquefied natural gas (vapor portion) is separated in a demethanizer into a lean gas and a demethanized bottom product.

With respect to the power producing configurations of Figures 4 and 5, it should be noted that the same considerations apply for corresponding components and operating conditions as described above for plants according to Figures 1-3. Here, **Figure 4** exemplarily depicts a configuration in which power is generated and in which C_2 and C_3 components are recovered, whereas **Figure 5** exemplarily depicts a configuration in which power is generated and in which C_3 components are recovered.

In these configurations, after the LNG is pumped with pump 51 and heated in exchanger 54 to a two-phase stream, the LNG is separated in a separator 151. The separator vapor stream 101 is fed to the upper section of the demethanizer 56, and the separator liquid stream 102 is pumped by LNG booster pump 152 to about 2500 psig to 3500 psig forming stream 103. The pressurized liquid is heated by an external heat source in exchanger 153 using a heat medium 99 forming stream 104 at about 400°F to 500°F. Various heat sources can be applied, including waste heat sources from flue gas, process waste heat, and ambient heat and/ or fuel fired combustion heater, and the choice depends on availability and economics. Stream 104 is then expanded in an expander 154 to stream 105 at a pressure of about 400 psig to 500 psig, generating about 15,000 HP that can be used to supply the power requirement in the regasification process including pump 152 with the excess power being exported for sales.

The expander outlet stream 105 at about 200°F to 300°F is fed into demethanizer 56 operating at 400 psig to 500 psig. It should be especially noted that stream 105 supplies at least a portion, if not all of the reboiler heat required by the demethanizer. The reflux duty for demethanizer 56 is provided by inlet LNG stream 4, in exchanger 54. It should be especially noted that such reflux/stripping configurations are self-contained and typically do not require

any additional heat consumption. If required, a side reboiler 57 or bottom reboiler 58 can be used to supplement the heating requirement. Demethanizer overhead 8 is re-condensed in exchanger 54, separated in separator 59 with the liquid pumped by pump 60 to form stream 12, and with the lean LNG 14 (via 10 and 13) being further heated in exchanger 65 and 62. It should be recognized that higher expander inlet pressure may be used to increase power output and efficiency. However, there is an economic trade-off between higher power revenues and the higher equipment costs. In most cases, higher expander pressure is only desirable where electric power can be sold at a premium.

In additionally contemplated aspects of the inventive subject matter, it should also be recognized that an LNG plant can also be operated in an ethane recovery or ethane rejection (propane recovery) mode as depicted in the exemplary plant configuration of **Figure 6**. Here, ethane recovery can be varied from about 2% to about 80% as needed to meet the ethane market demand. The term "about" where used herein in conjunction with a numeral refers to a +/- 10% range of that numeral. The configuration of such process is similar to that of Figure 2 with some variations. Thus, and with respect to the configurations of Figures 6 and 7, it should be noted that the same considerations apply for corresponding components and operating conditions as described above for plants according to Figure 2.

In plants according to Figure 6, the rich LNG heating system is configured in one or more heating and separation steps prior to the demethanizer 56. LNG stream 5 from exchanger 54 is heated using the deethanizer reflux condenser duty in exchanger 65, and is further heated in exchanger 55 using an external heat source 91 forming stream 6. The two phase stream 6 is then separated in separator 87 producing flashed vapor stream 73 that is routed to the upper section of the demethanizer 56 (via valve 86), and liquid stream 71 that is fed to the mid section of the demethanizer as stream 72 after the liquid stream is heated by an external heat source 99 in exchanger 88. Generally, the operation and conditions of for the demethanizer and deethanizer are similar to those in the plant of Figure 2 with the exception that the deethanizer overhead C2 liquid stream 26 is pumped by pump 89 to about 1300 psig or the sales pipeline pressure. The amount of ethane production can be varied by diverting at least a portion of the excess ethane liquid stream 75 via valve 90 to blend with the lean LNG stream 14 (and/or rich LNG stream 2, and/or mixture of streams 2 and 14) forming stream 77, prior to being heated in the conventional LNG vaporizer 62. Alternatively, this ethane blending method can be used to produce natural gas when a higher heating value is desirable

for the sales gas pipeline sales by increasing the ethane flow stream 75. Thereby, by varying the C2 flow using the diverting valve 90, the heating value of natural gas can be controlled and the amount of ethane production can be varied to meet facility requirements, regardless of the import LNG heating values.

Similarly, contemplated NGL recovery plants can also be operated to produce propane and ethane liquid product that can be pumped and transported to distant locations via a batching pipeline as shown in the exemplary plant configuration of **Figure 7,** similar to that of Figure 6 with some variations. Thus, and with respect to the configurations of Figure 7, it should be noted that the same considerations apply for corresponding components and operating conditions as described above for plants according to Figure 6.

Here, a single pipeline is used to transport either C2 or C3+, in an alternating mode to various pipeline systems or industrial sites and further includes liquid storage, pumping, and a batching pipeline. Most typically, one or more days of liquid product storage capacities are provided to ensure stable operation in C3+ product storage tank 100 and C2 product storage tank 101. High pressure liquid product pumps 89 and 102 are respectively used to pump the C2 or C3+ product to NGL pipeline 104 operating at typically 1300 psig or higher pressure. Using a single pipeline in delivering the C2 and C3+ product in a batching mode eliminates the need for two dedicated C2 and C3+ pipeline, significantly reducing pipeline associated costs.

Therefore, it should be appreciated that numerous advantages may be achieved using configurations according to the inventive subject matter. For example, contemplated configurations provide a highly efficient LNG power generation cycle that can be coupled with a heating control unit utilizing fractionation, and re-condensation. Viewed from another perspective, it should be appreciated that configurations contemplated herein allow LNG regasification plants to be less dependent on an external power supply, thus making such configurations even more economical and flexible while at the same time providing the capability of processing of LNG with varying compositions and heat contents to meet pipeline specifications.

Preferred configurations are suitable as an add-in unit for a new installation or as a retrofit installation for heating value control of the inlet LNG, producing a lean LNG, LPG and ethane. By controlling the portion of LNG feed and the levels of propane and ethane removal, the desirable heating value or liquid product flow can be maintained. Any type of

heat sources for regasification are deemed suitable, however, particularly preferred heat sources include waste heat from power plant.

Thus, it should be recognized that in some of preferred plants, a demethanizer and deethanizer operate in a manner in which the demethanizer removes C_2+ components from the LNG using reboiler and/ or side reboiler heat, and wherein at least a portion of reflux condensing duty of the demethanizer is provided by the refrigeration content of the rich LNG. Furthermore, the cold for the deethanizer overhead condenser may be provided by the refrigeration from the lean LNG after the lean LNG is pumped to pipeline pressure. Therefore, in one aspect of the inventive subject matter, at least a portion of the demethanizer overhead is cooled, partially condensed and separated, and the separated liquid is returned to the demethanizer as reflux with the separator lean gas (partially or entirely depleted in ethane), further cooled and condensed by inlet LNG forming a liquid phase. The liquid phase is then further pumped to pipeline pressure, supplying the refrigeration requirement of the deethanizer, and then heated in conventional vaporizers. The demethanizer bottom product may be fed to a deethanizer that produces ethane vapor and/or ethane liquid product and a liquefied petroleum gas product, wherein at least in some configurations the ethane product is employed as a fuel in the vaporizers or used as fuel gas in a power plant or be sold as a chemical feedstock. In further preferred aspects of contemplated plants, at least a portion of the reflux condenser duty of the deethanizer may be provided by the refrigeration content of a portion of the liquefied natural gas after the demethanizer reflux separator vapor is condensed and pumped to pipeline pressure.

Alternatively, or additionally, contemplated plants may include a deethanizer, wherein the inlet LNG (rich gas) or the outlet LNG (lean gas) provides reflux condenser duty for the deethanizer before the LNG is heated for pipeline specification. In at least some of such plants, the demethanizer may produce a bottom product that is fed to the deethanizer, wherein the deethanizer produces a liquefied petroleum gas (C_3+) product and an ethane product, which may then be sold for petrochemical feedstock or combusted as a turbine fuel in a combined cycle power plant. Where appropriate (*e.g.*, to reduce safety concerns), heating of the first portion is provided by a heat transfer fluid (*e.g.*, a glycol water mixture) that transfers heat from heat sources, such as fuel fired heater, ambient air, water circulating system, the gas turbine combustion air, the steam turbine discharge, the heat recovery unit, and/or the flue gas stream. Viewed from a different perspective, contemplated plants will

receive a liquid natural gas feed that is split in a first portion and a second portion, wherein the first portion enters the heating value control section, and wherein the second portion is fed to the vaporizer (most preferably after combination with the lean LNG).

In further especially contemplated plants, ethane recovery, ethane rejection, or varying levels of ethane production are met by diverting at least a portion of the liquid ethane product from the deethanizer overhead to blend with the lean LNG prior to being heated in the conventional vaporizers. Such configuration allows flexibility of switching between ethane recovery to ethane rejection mode, or *vice versa*, that may be necessary to meet the sales gas heating value specification or to accommodate the changes in the ethane market demand, while maintaining substantially the same process conditions in the demethanizer and deethanizer for all operations. Contemplated NGL recovery plant can also be operated to produce propane and ethane products that can be transported to distant pipeline systems or industrial sites via a single batching pipeline operating on alternating modes. The use of the batching pipeline has eliminated the need for two dedicated pipelines for C2 and C3+ products, significantly reducing the pipeline cost.

Examples

Exemplary Calculation of Components in Selected Streams

In an exemplary configuration substantially identical with the plant configuration as shown in Figure 1, the mol fraction of various components of selected streams were calculated, and the results are listed in Table 1 below. LPG is the C_3+ bottom fraction of the demethanizer stream 20, and the pipeline gas is depicted as stream 16 .

Table 1

Component	LNG Feed	Ethane	LPG	Pipeline Gas
N2	0.0065	0.0000	0.0000	0.0073
C1	0.8816	0.0176	0.0000	0.9878
C2	0.0522	0.9723	0.0053	0.0042
C3	0.0328	0.0092	0.5407	0.0006
iC4	0.0071	0.0000	0.1206	0.0000
NC4	0.0107	0.0000	0.1818	0.0000
iC5	0.0040	0.0000	0.0673	0.0000
NC5	0.0020	0.0000	0.0337	0.0000

C6 +	0.0030	0.0000	0.0505	0.0000
Heat Value Btu/SCF (HHV)	1,153	1,750	2,985	999
MMscfd	500	25	30	450
Barrel per day	218,000	16,000	21,000	181,000

Thus, specific embodiments and applications of LNG regasification configurations and methods have been disclosed. It should be apparent, however, to those skilled in the art that many more modifications besides those already described are possible without departing from the inventive concepts herein. The inventive subject matter, therefore, is not to be restricted except in the spirit of the appended claims. Moreover, in interpreting both the specification and the claims, all terms should be interpreted in the broadest possible manner consistent with the context. In particular, the terms "comprises" and "comprising" should be interpreted as referring to elements, components, or steps in a non-exclusive manner, indicating that the referenced elements, components, or steps may be present, or utilized, or combined with other elements, components, or steps that are not expressly referenced. Furthermore, where a definition or use of a term in a reference, which is incorporated by reference herein is inconsistent or contrary to the definition of that term provided herein, the definition of that term provided herein applies and the definition of that term in the reference does not apply.

CLAIMS

What is claimed is:

1. A LNG processing plant comprising:

   a LNG source that provides a first portion of LNG and a second portion of LNG;

   a processing unit that is fluidly coupled to the LNG source and that receives the first portion, wherein the unit is configured to remove heavier components in the first portion to thereby produce a lean LNG; and

   a combination unit in which the lean LNG and the second portion of the LNG are combined to a form a processed LNG.

2. The LNG processing plant of claim 1, further comprising a pump that pumps at least one of the first and second portions to a feed pressure.

3. The LNG processing plant of claim 2, further comprising a demethanizer that receives at least part of the second portion at a pressure lower than the feed pressure.

4. The LNG processing plant of claim 1 further comprising a demethanizer that produces an overhead product, wherein a heat exchanger cools at least part of the overhead product to thereby produce a reflux stream for the demethanizer.

5. The LNG processing plant of claim 1 further comprising a demethanizer reflux drum that produces an overhead product, wherein a heat exchanger condenses at least part of the overhead product to thereby produce the lean LNG.

6. The LNG processing plant of claim 5 further comprising a second pump that pumps the lean LNG to a delivery pressure.

7. The LNG processing plant of claim 1 wherein the combination unit is configured to combine the first portion and the lean LNG at pipeline pressure to thereby form the processed LNG.

8. The LNG processing plant of claim 1, further comprising a deethanizer that receives a demethanizer bottom product and that produces a C2 overhead product and a C3 bottom product.

9. The LNG processing plant of claim 8, further comprising a deethanizer overhead condenser that is configured to provide refrigeration to the C2 overhead product using refrigeration content of the first portion of the LNG.

10. The LNG processing plant of claim 1 further comprising a generator that is driven by expansion of a heated and pressurized portion of the first portion of LNG to thereby produce energy.

11. A LNG processing plant comprising a heat exchanger that is configured such that at least part of a refrigeration content of LNG passing through the exchanger provides refrigeration to a demethanizer reflux stream and further provides condensation cold for a demethanizer reflux drum overhead product, and wherein the reflux stream and the reflux drum overhead product are produced from the LNG passing through the exchanger.

12. The LNG processing plant of claim 11 further comprising a demethanizer, wherein the demethanizer is coupled to the exchanger such that at least part of the LNG passing through the exchanger is fed to the demethanizer to thereby form at least one of the demethanizer reflux stream and a condensed demethanizer reflux drum overhead product.

13. The LNG processing plant of claim 11 wherein the LNG passing through the exchanger has a pressure of between 300 psig to 600 psig.

14. The LNG processing plant of claim 11 further comprising a pump that pumps the condensed demethanizer reflux drum overhead product to a delivery pressure.

15. The LNG processing plant of claim 14 further comprising a combination unit in which the condensed demethanizer reflux drum overhead product at delivery pressure is combined with LNG.

16. A method of processing LNG, comprising:

providing LNG and pumping the LNG to a feed pressure;

dividing the LNG at feed pressure in a first and second portion;

providing the first portion to a separation pressure and separating heavier components from the first portion at the separation pressure to thereby form a lean LNG;

pumping the lean LNG to a delivery pressure; and

combining the lean LNG and the second portion of the LNG to form a processed LNG.

17. The method of claim 16 wherein the feed pressure is between about 700 psig and 1300 psig, the separation pressure is between about 300 psig and 650 psig, and wherein the delivery pressure is between about 700 psig and 1300 psig.

18. The method of claim 16 wherein separation of the heavier components from the first portion is performed in a demethanizer reflux drum that produces a demethanizer overhead product.

19. The method of claim 18 wherein at least one portion of the demethanizer reflux drum overhead product is condensed to thereby form the lean LNG, and optionally wherein another portion of the demethanizer overhead product is cooled to thereby form a reflux stream for the demethanizer.

20. The method of claim 16 wherein separation of the heavier components from the first portion is performed in a demethanizer and in a deethanizer, wherein a demethanizer bottom product is fed to the deethanizer.

21. The method of claim 16 wherein ethane rejection or varying levels of ethane recovery is performed by blending a portion of liquid ethane product from a deethanizer overhead with processed LNG from a demethanizer.

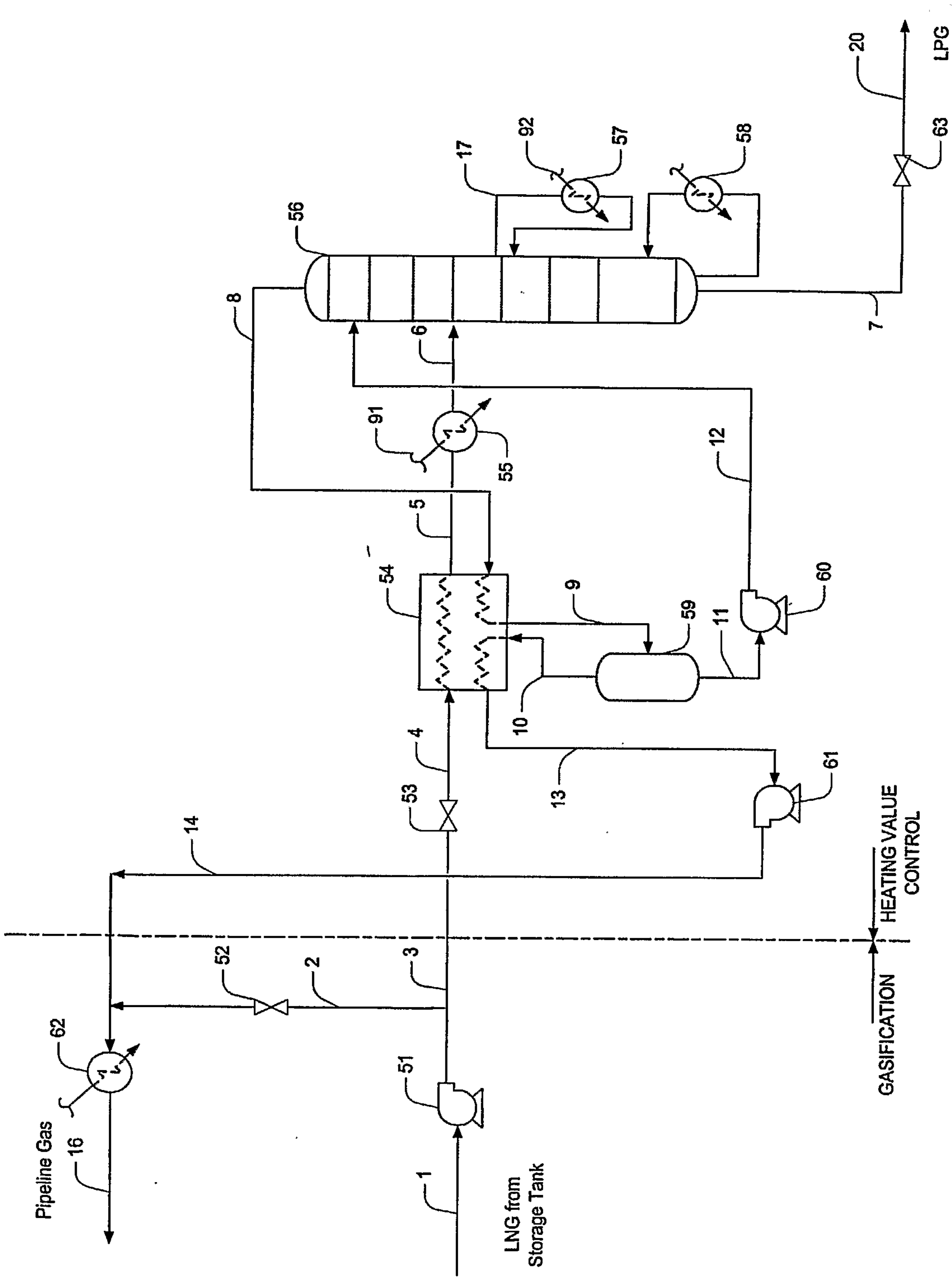
LPG
20
63
58
57
92
17
56
8
7
6
91
55
12
5
54
9
59
11
60
10
4
53
13
61
14
HEATING VALUE CONTROL
GASIFICATION
52
2
3
62
51
Pipeline Gas
16
1
LNG from Storage Tank

Figure 1

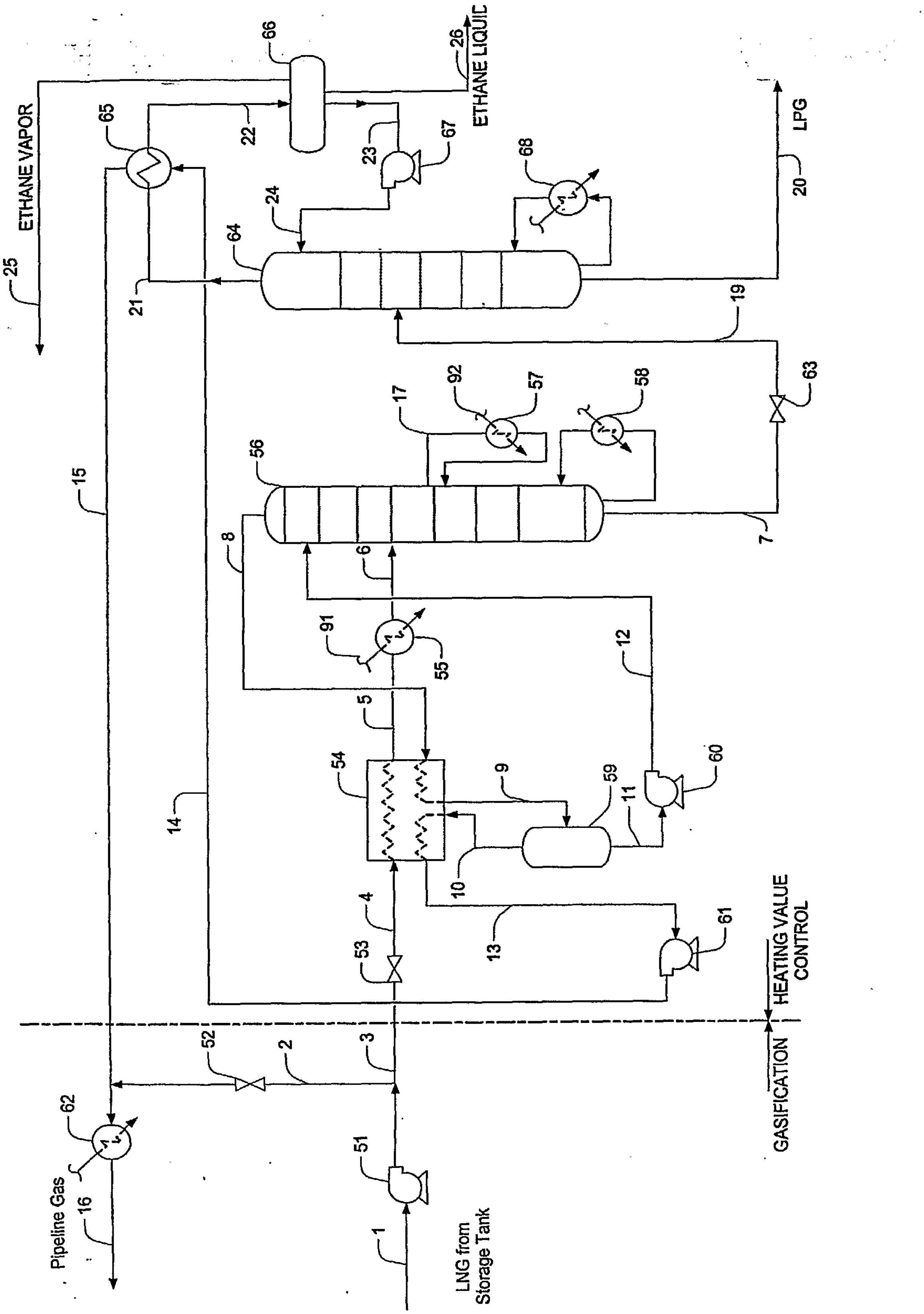
ETHANE VAPOR
ETHANE LIQUIC
LPG
HEATING VALUE
CONTROL
GASIFICATION
Pipeline Gas
LNG from
Storage Tank

Figure 2

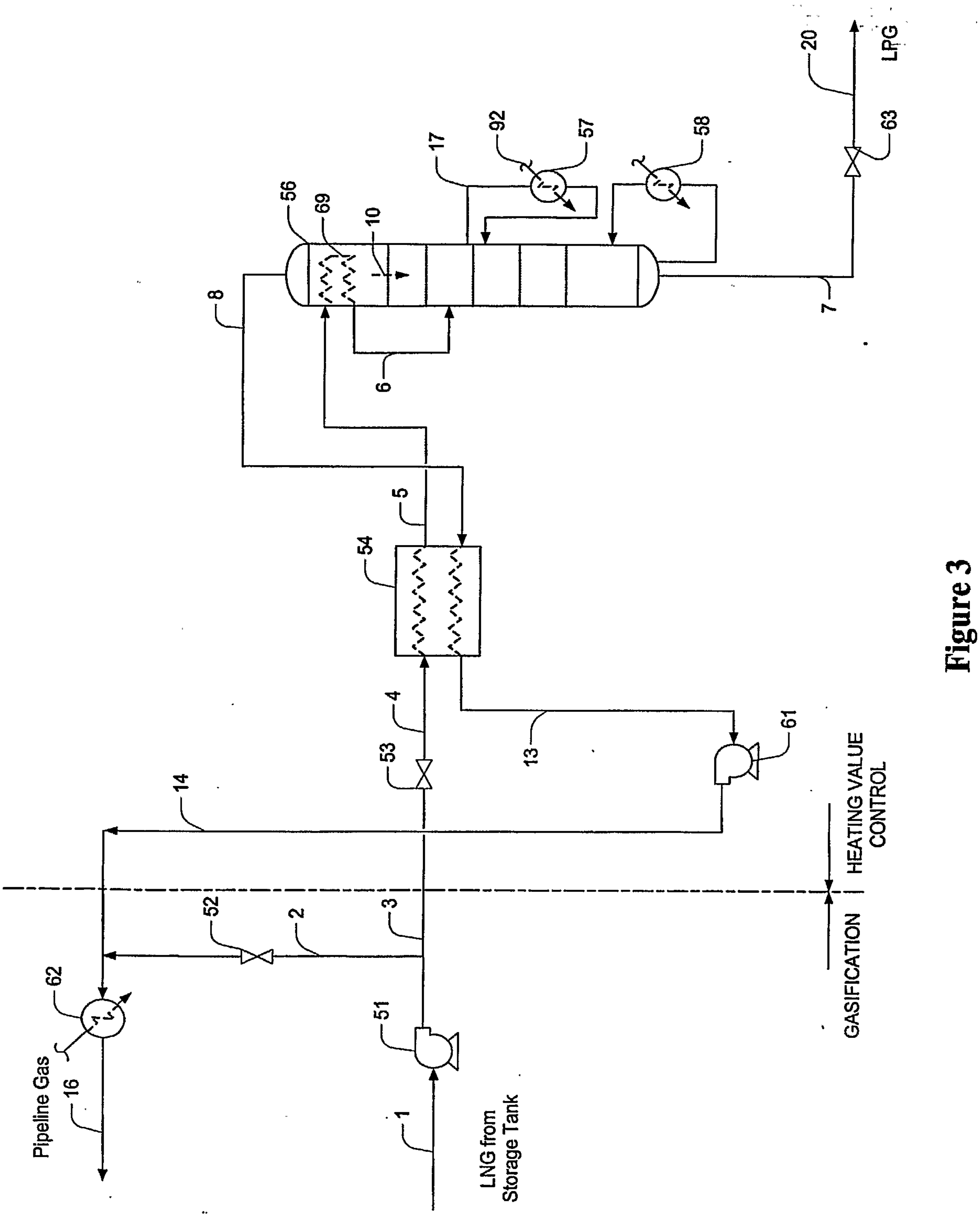
Pipeline Gas
16
62
51
1
LNG from Storage Tank
52
2
3
GASIFICATION
HEATING VALUE CONTROL
14
53
4
13
61
54
5
8
6
56
69
10
17
92
57
58
7
63
20
LPG

Figure 3

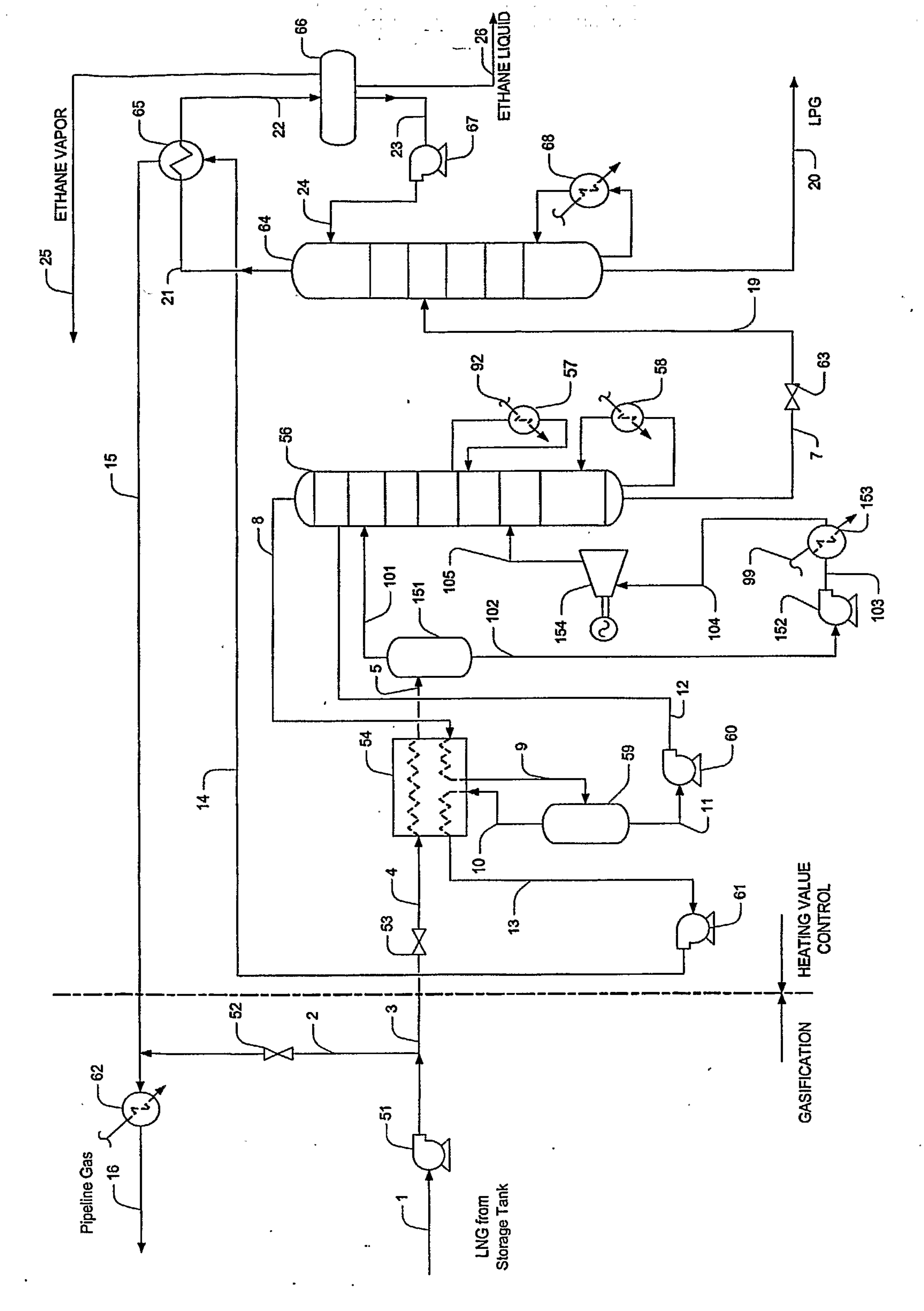
ETHANE VAPOR
ETHANE LIQUID
LPG
HEATING VALUE CONTROL
GASIFICATION
Pipeline Gas
LNG from Storage Tank

Figure 4

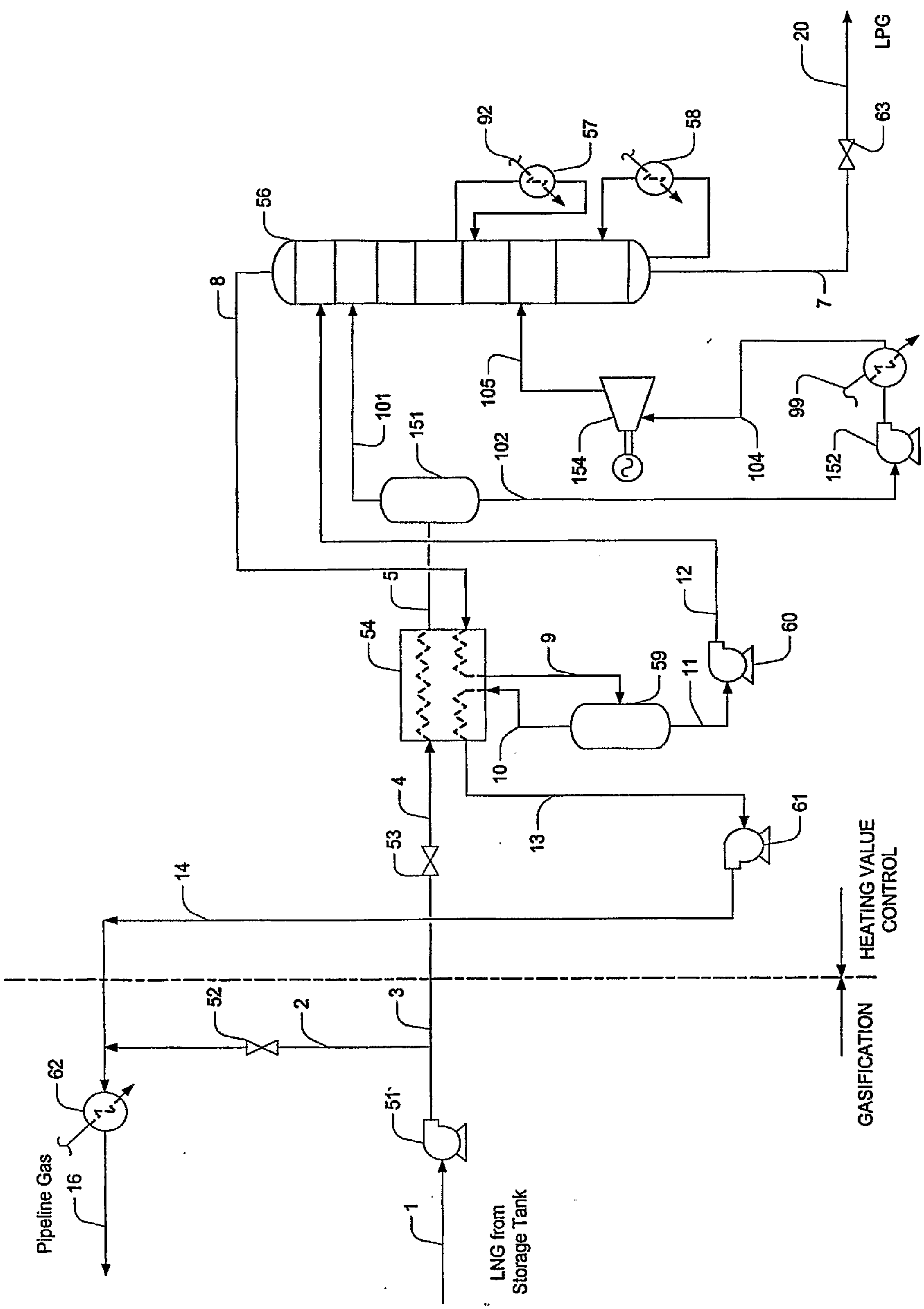
LPG
20
63
92
57
58
56
8
7
105
101
151
102
154
104
99
152
5
54
9
59
11
12
60
10
4
53
13
61
14
HEATING VALUE CONTROL
GASIFICATION
52
2
3
62
51
Pipeline Gas
16
1
LNG from Storage Tank

Figure 5

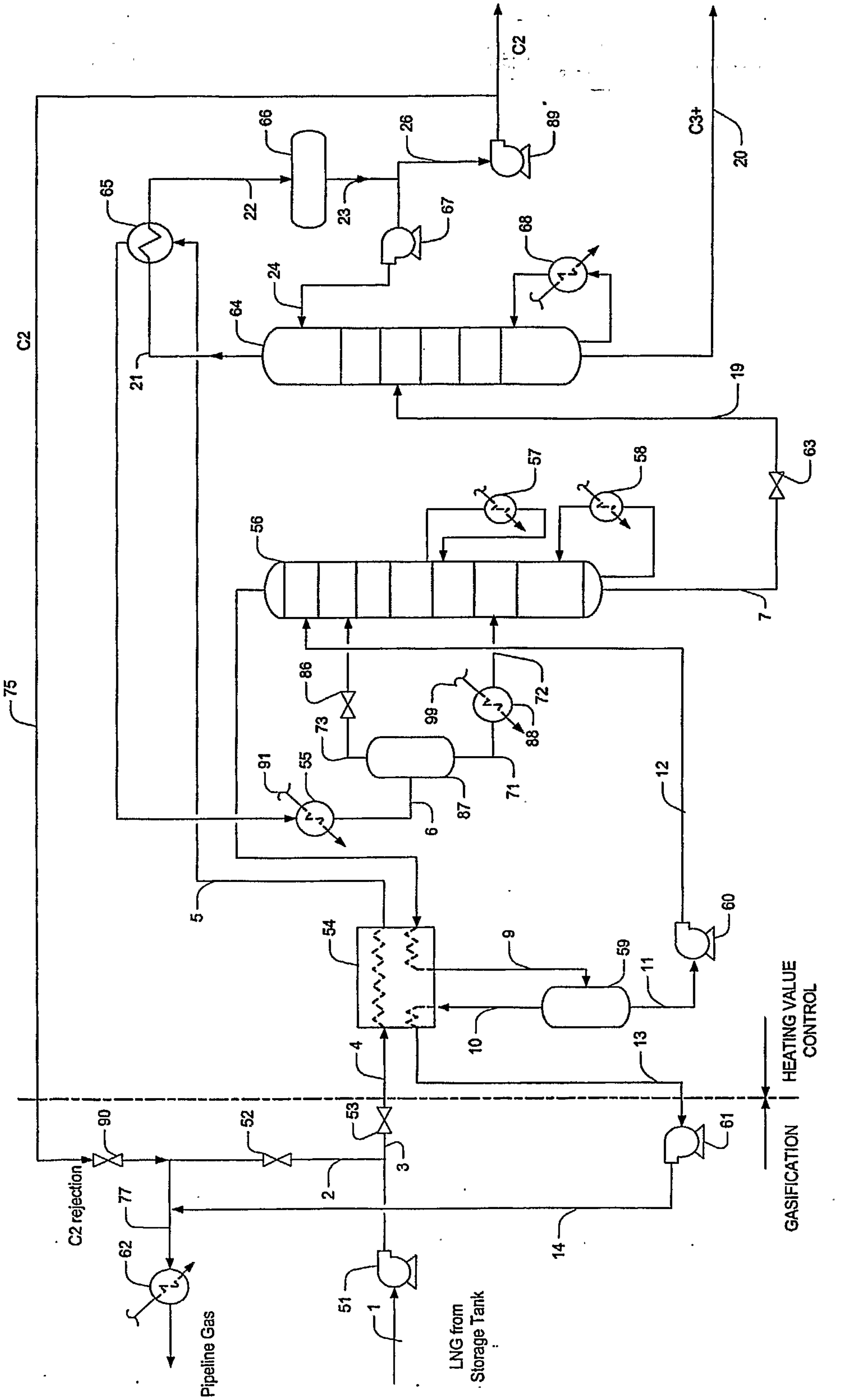
C2
C3+
C2
75
C2 rejection
Pipeline Gas
LNG from Storage Tank
HEATING VALUE CONTROL
GASIFICATION

Figure 6

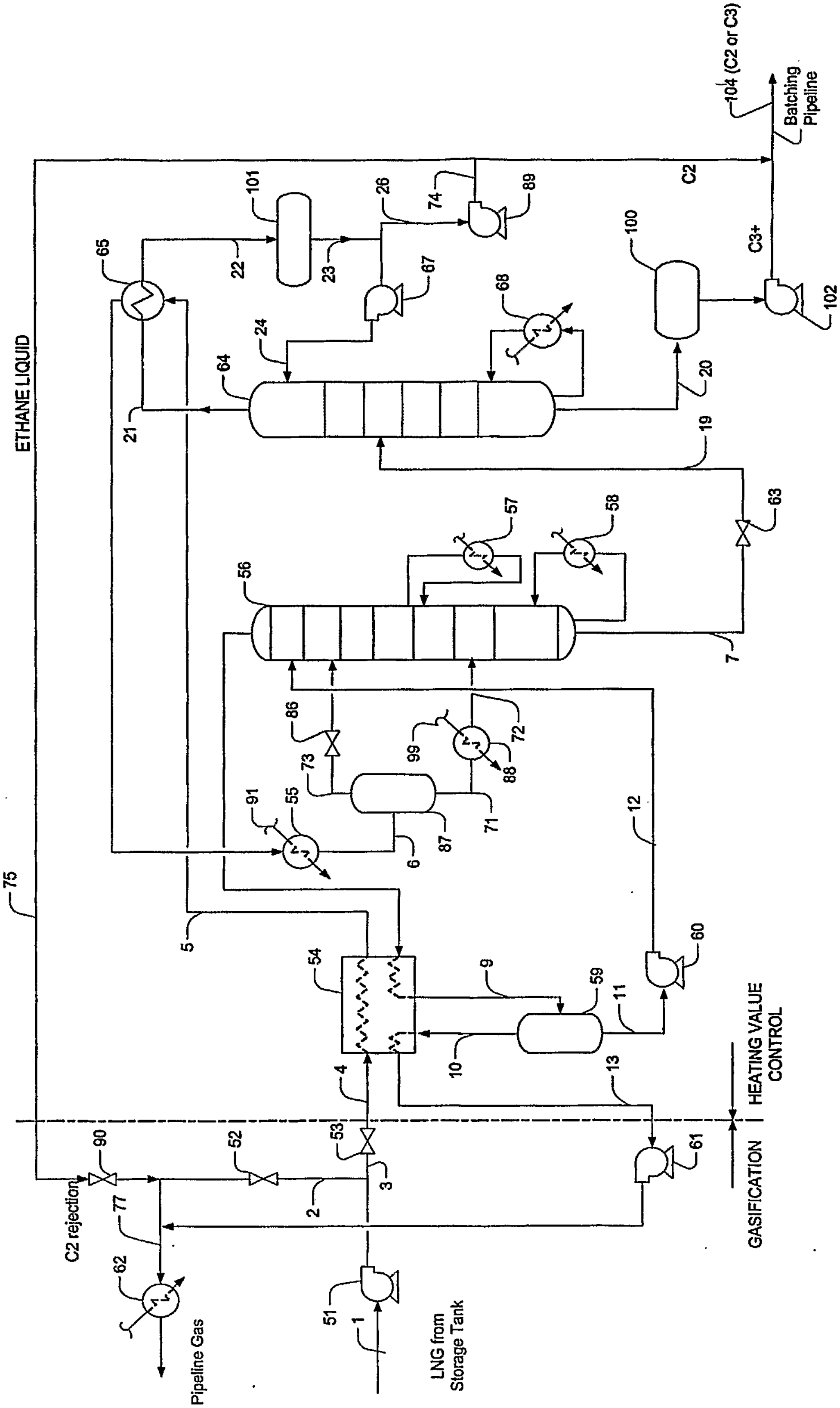
LNG from Storage Tank
Pipeline Gas
C2 rejection
GASIFICATION
HEATING VALUE CONTROL
ETHANE LIQUID
C2
C3+
Batching Pipeline
104 (C2 or C3)

Figure 7

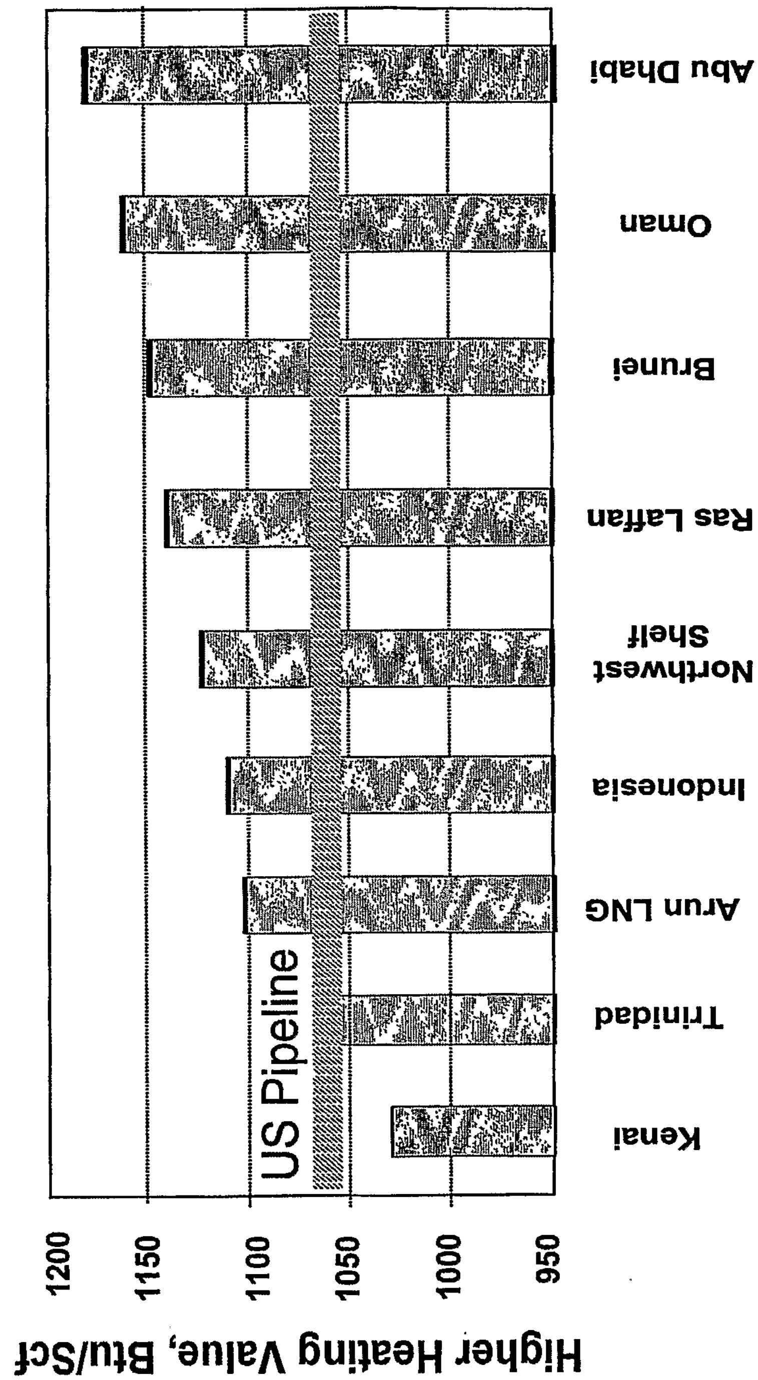
Higher Heating Value, Btu/Scf
1200
1150
1100
1050
1000
950
US Pipeline
Kenai
Trinidad
Arun LNG
Indonesia
Northwest Shelf
Ras Laffan
Brunei
Oman
Abu Dhabi

Figure 8

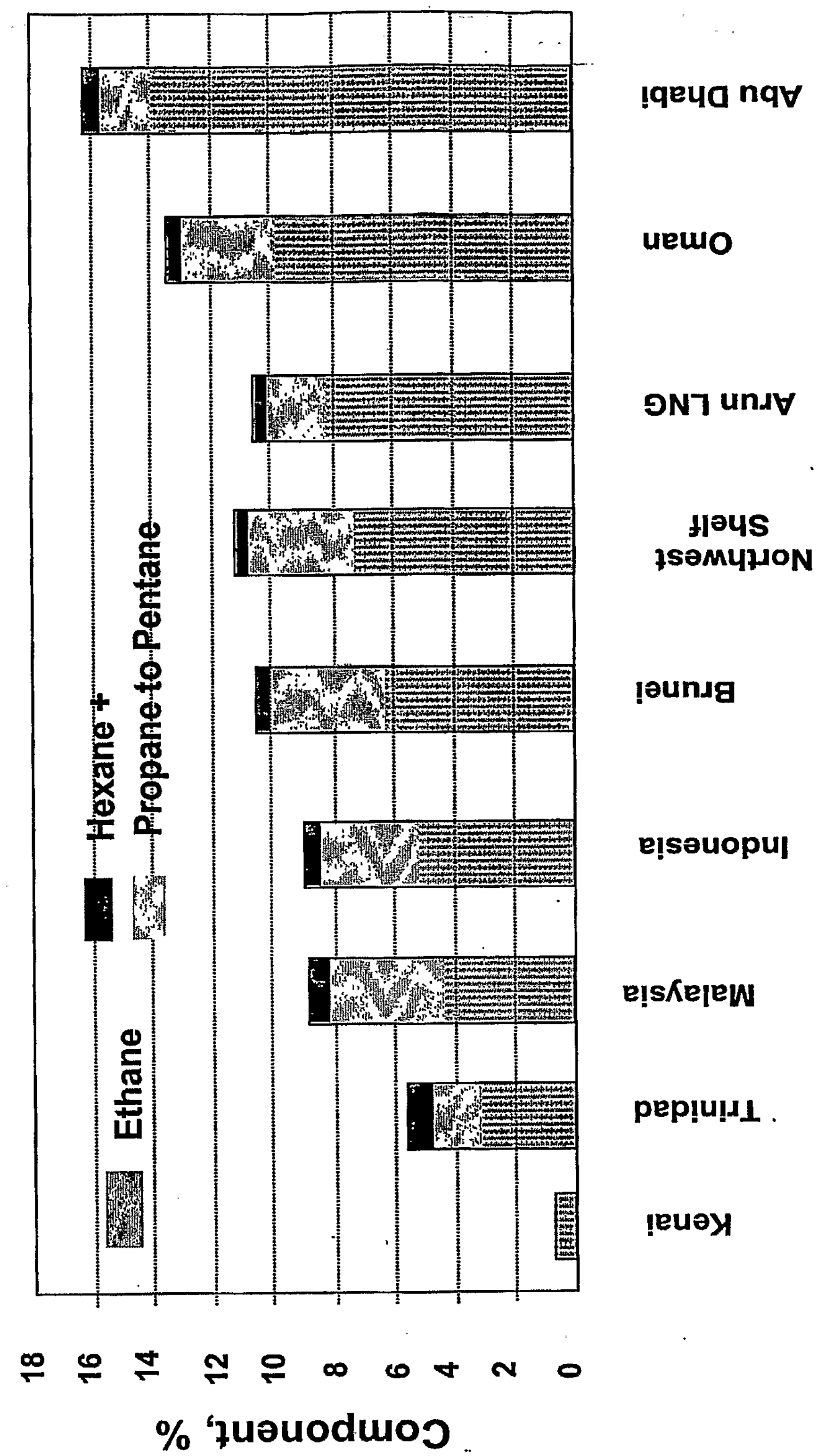
Ethane
Hexane +
Propane to Pentane
Component, %
18
16
14
12
10
8
6
4
2
0
Kenai
Trinidad
Malaysia
Indonesia
Brunei
Northwest Shelf
Arun LNG
Oman
Abu Dhabi

Figure 9

INTERNATIONAL SEARCH REPORT

International application No.
PCT/US05/22880

A. CLASSIFICATION OF SUBJECT MATTER
IPC(7) : F25J 3/00; F17C 9/02
US CL : 62/620, 50.2
According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
U.S. : 62/620, 50.2,625, 631, 635

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched
None

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
None

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
A	US 5,114,451 A (RAMBO et al) 19 May 1992 (19.05.1992), see entire document.	1-21
A	US 3,405,530 A (DENAHAN et al) 15 October 1968 (15.10.1968), see entire document.	1-21
X, E	US 2005/0155381 A (YANG et al) 21 July 2005 (21.07.2005), see entire document.	1,4,5,8,9,11,12
A	US 6,564,579 B1 (McCARTNEY) 20 May 2003 (20.05.2003), see entire document.	11-15

☐ Further documents are listed in the continuation of Box C. ☐ See patent family annex.

* Special categories of cited documents:

"A" document defining the general state of the art which is not considered to be of particular relevance

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"O" document referring to an oral disclosure, use, exhibition or other means

"P" document published prior to the international filing date but later than the priority date claimed

"T" later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

"X" document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

"Y" document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

"&" document member of the same patent family

Date of the actual completion of the international search
27 September 2005 (27.09.2005)

Date of mailing of the international search report
10 NOV 2005

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